

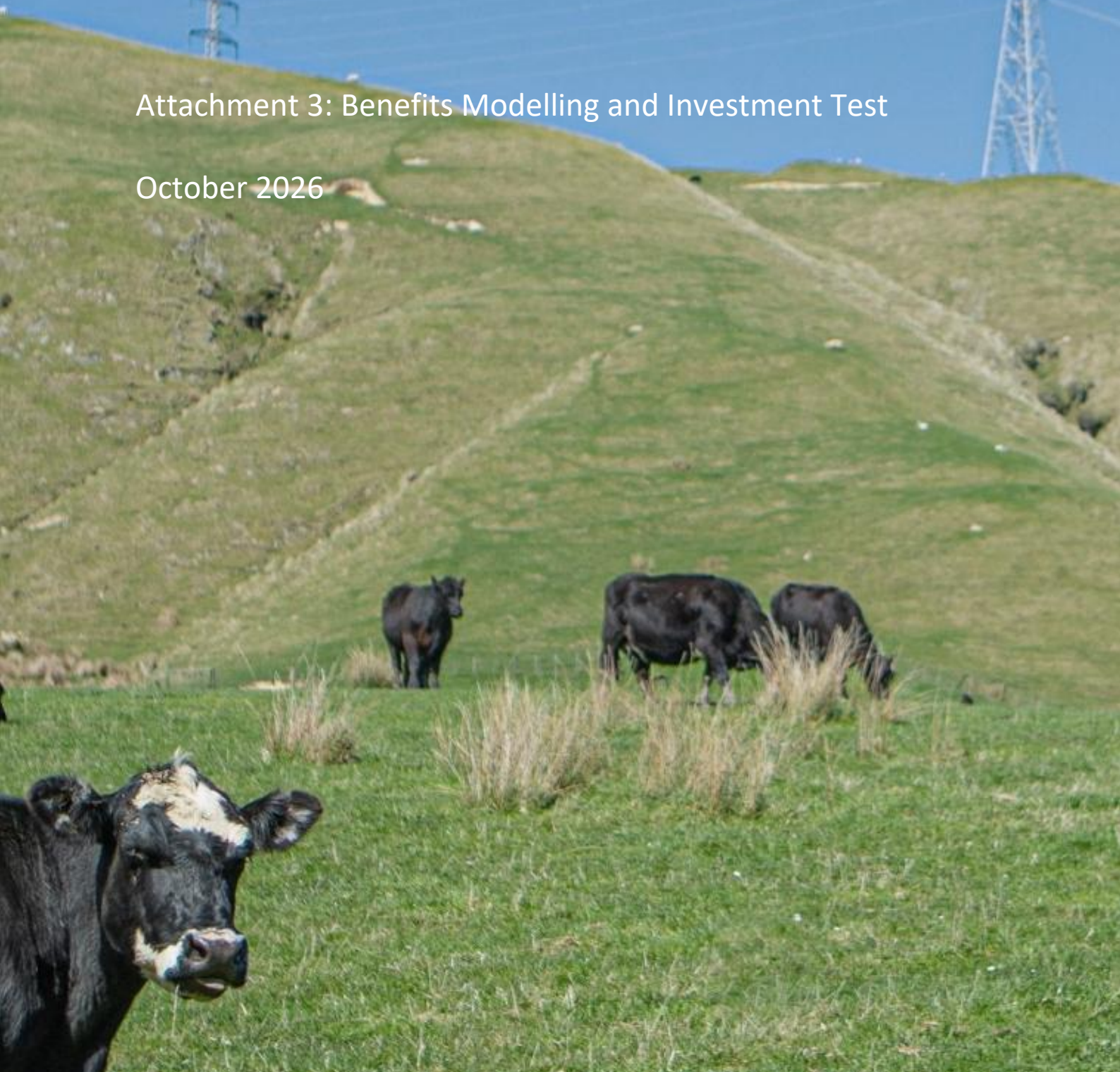


TRANSPOWER

Waikato Regional Interconnection Capacity (WRIC): Major Capex Proposal Shortlist Consultation

Attachment 3: Benefits Modelling and Investment Test

October 2026



Contents

1	Benefits modelling approach	3
2	Economic modelling inputs	4
2.1	Value of Expected Unserved Energy	4
2.2	Discount rate	4
2.3	Calculation period	4
3	Option-related costs and terminal values	4
3.1	Investment option capital costs.....	4
3.2	Modelled projects.....	5
3.3	Terminal values	7
3.4	Maintenance costs.....	8
3.5	Option related costs and terminal values by scenario	8
4	Reliability modelling	10
4.1	Grid reliability model	10
4.2	A note on SDDP.....	11
4.3	Reliability costs.....	11
5	Results	13
5.1	Quantified costs and benefits.....	13
5.2	Investment test.....	14
5.3	Sensitivity analysis.....	15
5.4	Unquantified benefits	16

1 Benefits modelling approach

This attachment describes the approach used to quantify the economic costs and benefits of the Waikato Regional Interconnection Capacity investment options.

Power system studies of the Waikato 110 kV network were used to identify the need date for additional interconnection capacity and to assess how each investment option would affect future power flows and network constraints.

Reliability modelling was then used to estimate expected unserved energy under the counterfactual and each investment option. The modelling considers three types of contingency event and estimates the associated expected unserved energy, transformer repair costs and, for the counterfactual, any required pre-contingent demand response.

The modelling also assessed how each option influences the timing of future network upgrades, with the benefits of this captured through the time value of project deferral.

We have not used SDDP, Transpower's standard market modelling tool, to estimate the benefits of the WRIC investment. The principal benefits of the investment arise from improved reliability during planned and unplanned outages, rather than changes in generation dispatch or market outcomes. An initial assessment confirmed that a reliability-based modelling approach was therefore more appropriate for estimating investment benefits than market modelling using SDDP.

2 Economic modelling inputs

2.1 Value of Expected Unserved Energy

The analysis used a value of expected unserved energy (VoEUE) of \$33,000 per MWh. This is consistent with the value proposed and accepted through the project's longlist consultation. We also present sensitivity results for values of \$10,000, \$20,000 and \$50,000 per MWh.

2.2 Discount rate

The discount rate is a key assumption in the economic assessment of options because it converts future costs and benefits into 2026 present values, affecting the relative weight placed on upfront capital costs, later reliability benefits, modelled project deferral benefits and terminal values. This assessment applies the 5% real discount rate specified in the Capex IM¹, with 3% and 7% sensitivities used to test whether the preferred option is robust to reasonable changes in this assumption.

2.3 Calculation period

We use the default 20-year calculation period specified for the investment test. If this shortlist consultation leads to a Major Capex Proposal being approved, this period will commence on the commissioning date of the last asset delivered by the proposed investment. This is currently envisaged as July 2030.

Since the economic lifetime of the options extends beyond 2050, these assets will still retain value at the end of the calculation period. To account for this, we have included a terminal value, which reduces the net cost attributed to the asset by recognising its remaining value at the end of the calculation period. A linear depreciation approach is used to decrease the cost of the asset over its expected lifetime.

We consider this calculation period, and the inclusion of terminal values, to be an appropriate trade-off between assessing benefits over the full economic life of an option and the uncertainty of benefits that occur further in the future. Feedback from the longlist consultation supported this approach.

3 Option-related costs and terminal values

3.1 Investment option capital costs

Option costs have been estimated at Class 4 level as is standard for shortlist consultation.

¹ [CAPEX IM](#)

Table 1: Investment option cost estimates; costs in 2026 dollars

Cost category	Option 2: Hamilton East	Option 3: Ōtorohanga
Civil works	\$5.6	\$6.4
Buildings	\$1.4	\$1.4
Primary Plant	\$17.7	\$16.1
Protection	\$6.2	\$4.7
Communications	\$0.9	\$1.8
Freight	\$0.3	\$0.3
Lines	\$2.7	\$1.2
Design	\$1.6	\$1.5
Overheads	\$7.1	\$6.5
Environmental	\$0.6	\$1.5
Community	\$0.2	\$0.3
Risk	\$3.5	\$4.2
Total	\$47.9	\$46.0

Table 1 presents the estimated capital cost in constant 2026 dollars. In Tables 3–5, forecast expenditure is discounted from the expected construction period to a 2026 present value. This results in capital costs of \$42.6 million for Hamilton East and \$40.9 million for Ōtorohanga for investment test purposes.

3.2 Modelled projects

Both investment options affect the timing and need for future Waikato 110 kV network investments. This is because locating additional interconnection capacity at Hamilton East or Ōtorohanga changes regional power flows and therefore changes when subsequent thermal, voltage, and security constraints arise.

Table 2 presents the assumed cost of each modelled project and its option-dependent need date under each scenario. Deferring a modelled project provides an economic benefit through the time value of money, while bringing a project forward increases its present-value cost. The present values

of these modelled project costs, together with the associated maintenance costs and terminal values, are included in the scenario results presented in Tables 3–5.

The modelled project timings also illustrate Hamilton East’s flexibility advantage under higher-load futures. In the Growth scenario, the Ōtorohanga option requires a fourth interconnecting transformer in 2048, whereas this investment is not required under the Hamilton East option within the modelling horizon.

Table 2: Modelled project need dates, by option and scenario; costs in 2026 dollars²

Modelled Project ³	Cost, (\$m, 2026)	Constraint scenario			Environmental scenario			Growth scenario		
		Opt. 1	Opt. 2	Opt. 3	Opt. 1	Opt. 2	Opt. 3	Opt. 1	Opt. 2	Opt. 3
New Hamilton–Waihou line	\$51.6	2034		2039	2034		2039	2039 ⁴		2043
Hamilton–Morrinsville–Waihou Special Protection Scheme (SPS)	\$0.8	2030	2034	2030	2030	2034	2030	2031	2035	2031
Cambridge SPS	\$0.8	2040	2040		2040	2040				
Karapiro–Te Awamutu Tactical Transmission Upgrade (TTU)	\$6.8	2048	2048		2048	2048		2047	2047	2054
Reconductor Arapuni–Hangatiki and Arapuni–Rangitoto, TTU Arapuni–Hangatiki and Hangatiki–Rangitoto	\$20.1	2053	2054		2053	2054		2045	2045	
Fourth interconnecting transformer	\$47.9									2048

² A blank cell indicates that the modelled project is not required under that option and scenario within the modelling horizon.

³ Opt. 1 is the counterfactual, Opt. 2 is the Hamilton East Option, and Opt. 3 is the Ōtorohanga option.

⁴ This investment is deferred under the Growth scenario due to expected generation connections in this part of the network.

Valley Spur project deferral

Since the longlist consultation, we have updated the forecasts and planning assumptions used to determine the need date for the Hamilton-Waihou⁵ line. This update reflects recent generation developments and further developer interest along the Valley Spur.

Previously, we assumed that a third Valley Spur circuit would be needed early to resolve both thermal and voltage issues. However, with additional existing and planned generation in the area, including likely future battery energy storage systems (BESS), it is now considered less likely. We have therefore updated the modelling approach so that the need date for the third circuit is determined by the forecast binding date of the voltage stability limit.

Peak load on the Valley Spur already exceeds the N-1 thermal capacity of the Hamilton–Morrinsville Tee sections of the Hamilton–Piako–Waihou circuit, and there is increasing risk of voltage instability⁶ on the Valley Spur as demand grows.

In the short term, the thermal overload on the Hamilton–Morrinsville Tee sections and the Kopu low-voltage issue can be managed through a special protection scheme that manages load post-contingency. However, this scheme does not address the voltage step issue and does not provide a long-term solution to the emerging voltage stability constraint. In the longer term, a third circuit from Hamilton, or Hamilton East, to Waihou would resolve both the thermal and voltage constraints on the Valley Spur.

This updated assumption materially affects the option comparison. The Hamilton East option is projected to defer the third Valley Spur circuit beyond 2049, while the Ōtorohanga option still requires the investment within the calculation period. This deferral is the principal source of Hamilton East’s advantage in modelled-project costs.

3.3 Terminal values

Terminal values have been included to recognise that some assets and modelled investments continue to provide value beyond the end of the calculation period in 2050. Without a terminal value adjustment, the investment test would overstate the cost of investments made late in the study period and could distort the comparison between options with different timing profiles.

For each option, terminal values are calculated as the discounted residual value of relevant capital investments at the end of the modelling period. This includes the residual value of the proposed interconnecting transformer investment and modelled regional projects where those assets have remaining economic life beyond 2050. The terminal values are treated consistently across the counterfactual and investment options and are included as positive values in the cost-benefit calculation.

⁵ Otherwise referred to as the Valley Spur line.

⁶ Power system studies indicate an increasing risk of voltage instability on the Valley Spur as demand grows. A Hamilton–Piako–Waihou circuit outage during high-load periods will result in supply bus voltage steps exceeding 5% at Piako, Waihou, Waikino and Kopu. Under the same outage, Kopu 110 kV voltage is forecast to fall below 0.9 p.u. from 2030, and the voltage stability limit is forecast to bind from 2034.

Terminal values do not materially change the option ranking: the Hamilton East option remains the preferred investment option after terminal values are included.

3.4 Maintenance costs

Maintenance costs have been included as annual operating costs and discounted to 2026 present value. They reflect the ongoing cost of maintaining the investment options and any modelled regional projects required under each option. The differences in maintenance costs between options are relatively small compared with capital costs and terminal values, but including these costs ensures the options are compared on a consistent whole-of-life cost basis.

3.5 Option related costs and terminal values by scenario

The following tables present the option related costs and terminal values by scenario⁷. The capital cost and commissioning date of each investment option do not vary by scenario. However, the need dates for modelled projects do vary, affecting the present value of capital and maintenance costs and the terminal values at the end of the calculation period.

Table 3: Option related costs and terminal values, Environmental scenario; (\$m, 2026 present value @ 5% discount rate)

Component	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Capital cost (2026 \$m)	0.0	-42.6	-40.9
Modelled projects (transmission)	-43.3	-3.6	-31.2
Operating expenditure (maintenance costs)	-4.1	-5.3	-7.4
Terminal values	14.3	12.2	22.9
Net option related value (2026, \$m)	-33.1	-39.2	-56.6

Table 4: Option related costs and terminal values, Constraint scenario; (\$m, 2026 present value @ 5% discount rate)

Component	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Capital cost (2026 \$m)	0.0	-42.6	-40.9

⁷ Negative numbers are costs, and positive numbers are benefits.

Modelled projects (transmission)	-43.3	-3.6	-31.2
Operating expenditure (maintenance costs)	-4.1	-5.3	-7.4
Terminal values	14.3	12.2	22.9
Net option-related value (2026, \$m)	-33.1	-39.2	-56.6

Table 5: Option related costs and terminal values, Growth scenario; (\$m, 2026 present value @ 5% discount rate)⁸

Component	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Capital cost (2026 \$m)	0.0	-42.6	-40.9
Modelled projects (transmission)	-42.8	-12.1	-43.5
Operating expenditure (maintenance costs)	-2.9	-5.6	-6.7
Terminal values	21.8	18.0	39.5
Net option related value (2026, \$m)	-23.9	-42.4	-51.6

⁸ Totals may not sum due to rounding.

4 Reliability modelling

As highlighted in Attachment 1, peak net load on the Waikato 110 kV network is expected to surpass the N-1 capacity of the two Hamilton interconnecting transformers in the near term. The System Operator does not dispatch generation to ensure N-1 security on these transformers, as transformer outages are treated as extended contingent events (ECEs). Post-contingent overloads following an outage are managed by the System Operator through actions such as generation redispatch, grid reconfiguration or load control.

Expected unserved energy was modelled across three types of contingency event:

- **N-1:** The model estimates the impact of a single unplanned outage of one of the two interconnecting transformers. When forecast load exceeds the N-1 limit, the model estimates the resulting expected unserved energy.
- **N-2:** The model also considers the concurrent loss of the two interconnecting transformers at Hamilton. Although less frequent than N-1 events, an N-2 event will result in a greater level of expected unserved energy.
- **N-1-1:** This scenario occurs when the network is already operating under a planned outage, such as maintenance on an interconnecting transformer or transmission line, and an unplanned outage occurs.

For reliability modelling, we assume that a combined minimum of 150 MW from Mercury Energy's Arapuni and Karapiro hydro stations is available during peak demand periods, consistent with the generation assumptions set out in Attachment 2. These peak demand periods are expected to occur in winter, around dawn or after sunset, so we assume little or no contribution from the region's solar generation during these periods.

4.1 Grid reliability model

A tool has been developed to support grid reliability studies.

The model estimates the expected reliability costs under the counterfactual and each investment option. These reliability costs are then combined with the option-related costs and terminal values presented in section 3 to calculate the Expected Net Electricity Market Benefit (ENEMB) of each investment option. The model considers N-1 and N-2 events. In addition to expected unserved energy, it calculates the expected cost of transformer failure and, where relevant, the cost of pre-contingent demand response.

The expected cost for each outage state is calculated by combining the probability of the outage, the duration of the exposure, and the estimated cost impact.

$$\begin{aligned} \text{Reliability Benefit} &= \text{Cost of Unserved Energy (Counterfactual)} \\ &\quad - \text{Cost of Unserved Energy (Investment Option)} \end{aligned}$$

4.1.1 N-1-1 analysis

The Waikato region also faces security challenges during planned maintenance outages on the following components:

- a Hamilton interconnecting transformer;
- the 220 kV Hamilton–Ōhinewai circuit; or
- the 220 kV Hamilton–Whakamaru circuit.

These planned maintenance outages subject numerous grid-exit points (GXPs) in the region to N-security, which requires the Waikato 110 kV network to be split at multiple locations to mitigate the risk of any potential voltage collapse spreading beyond the region.

To estimate the reliability risk associated with an N-1-1 event, the load at risk was first calculated using forecast Waikato 110 kV demand and the assumed network configuration during planned outages. Historical outage data for the Hamilton interconnecting transformers and their associated connecting circuits was then used to estimate the likelihood of an unplanned outage occurring during a planned outage. The expected reliability cost was calculated as the load at risk multiplied by the probability of an N-1-1 event and the Value of Expected Unserved Energy.

$$\text{Expected Reliability cost (N-1-1)} = \text{Probability of N-1-1 event} \times \text{Load at risk (MWh)} \\ \times \text{Value of Expected Unserved Energy (\$/MWh)}$$

The Hamilton East option reduces this N-1-1 exposure more effectively than the Ōtorohanga option because it avoids the need to operate parts of the Waikato 110 kV network at N-security during relevant maintenance outages. In contrast, the Ōtorohanga option is still assumed to require a system split during these periods, limiting access to the Ōtorohanga interconnecting transformer and leaving some of the Waikato GXPs exposed to N-security.

4.2 A note on SDDP

We have not used SDDP⁹ because the principal benefits of the WRIC investment arise from improved reliability during planned and unplanned outages. SDDP is primarily a generation dispatch and market modelling tool and is not well suited to modelling the N-1, N-2 and N-1-1 events that drive these benefits. These events are more appropriately assessed through the reliability modelling described earlier in section 4.

An initial high-level SDDP assessment indicated that relieving the interconnection constraint would provide limited additional market benefits. Given both the significant cost and time required to undertake a full SDDP study, and the assessment's finding that further market modelling was unlikely to materially affect the relative ranking of options, we concluded that an SDDP study would add limited decision value and was therefore not warranted.

4.3 Reliability costs

The following tables present the expected reliability costs associated with the counterfactual and each investment option. These costs vary by scenario, with higher expected costs generally arising under higher-demand futures.

⁹ [SDDP - Systems Operation Planning - PSR Energy](#) SDDP (Stochastic Dual Dynamic Programming) is a stochastic dispatch model for electric power systems, with a detailed representation of transmission and fuel networks. It is used in long, medium, and short-term operational studies.

Table 6: Reliability costs, Environmental scenario (\$m, 2026 present value @ 5% discount rate)

Cost category	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Reliability costs – expected unserved energy	-11.5	-1.5	-8.1
Reliability costs – cost of failure	-4.3	-4.6	-4.6
Reliability costs – pre-contingent demand response	-4.0	0.0	0.0
Net expected reliability cost (2026, \$m)	-19.8	-6.1	-12.8

The Constraint scenario represents a lower-demand future, while the Growth scenario represents a higher-demand future. Expected unserved energy is greater under the Growth scenario. In the counterfactual, higher demand also increases the periods during which load may exceed the N-1 trip limit of the existing interconnecting transformers, increasing the need for pre-contingent demand response.

Table 7: Reliability costs, Constraint scenario (\$m, 2026 present value @ 5% discount rate)

Cost category	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Reliability costs – expected unserved energy	-8.1	-1.4	-7.1
Reliability costs – cost of failure	-4.3	-4.6	-4.6
Reliability costs – pre-contingent demand response	0.0	0.0	0.0
Net expected reliability cost (2026, \$m)	-12.4	-6.0	-11.7

Table 8: Reliability costs, Growth scenario (\$m, 2026 present value @ 5% discount rate)¹⁰

Cost category	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
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¹⁰ Totals may not sum due to rounding

Reliability costs – expected unserved energy	-13.3	-1.5	-8.3
Reliability costs – cost of failure	-4.3	-4.6	-4.6
Reliability costs – pre-contingent demand response	-9.6	0.0	0.0
Net expected reliability cost (2026, \$m)	-27.3	-6.1	-12.9

5 Results

5.1 Quantified costs and benefits

For each scenario, we calculated the total quantified value of the counterfactual and each investment option by combining:

- the option-related costs and terminal values presented in section 3; and
- the expected reliability costs presented in section 4.

All values are expressed as 2026 present values. Costs are shown as negative values and terminal values as positive values. The ENEMB of an investment option is calculated by subtracting the counterfactual's total net quantified value from the option's total net quantified value. Because costs are presented as negative values, a positive ENEMB means that the option has a lower total expected cost than the counterfactual.

For the overall investment test assessment, we weighted the scenario results as follows: Constraint 20%, Environmental 60%, and Growth 20%. This produces a single scenario-weighted comparison of the options. The rationale for the selected scenarios and their weightings is discussed in Attachment 2, section 1.1.

Table 9: Scenario-weighted quantified values (\$m, 2026 present value @ 5% discount rate)

Scenario	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Constraint	-45.5	-45.3	-68.3
Environmental	-52.9	-45.3	-69.4
Growth	-51.2	-48.5	-64.5
Weighted net quantified value (2026, \$m)	-51.1	-46.0	-68.2

5.2 Investment test

The investment test identifies the investment option with the highest expected net electricity market benefit as the preferred investment option. Table 10 applies this test by comparing the scenario-weighted net quantified value of each investment option with the counterfactual.

Table 10: Scenario-weighted net quantified values and ENEMB (\$m, 2026 present value @ 5% discount rate)

Investment test measure	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Net quantified value (2026, \$m)	-51.1	-46.0	-68.2
Expected Net Electricity Market Benefit¹¹ (relative to the counterfactual)	0.0	5.1	-17.1

On a scenario-weighted basis, Hamilton East has the highest Expected Net Electricity Market Benefit (ENEMB). It has an ENEMB of \$5.1 million relative to the counterfactual and \$22.2 million relative to the Ōtorohanga option. Hamilton East also meets the Grid Reliability Standard and is therefore our preferred investment option under the investment test. The unquantified benefits discussed in section 5.4 provide additional support for this conclusion.

Hamilton East's principal advantage in modelled-project costs is that it defers the need for a third Hamilton/Hamilton East–Waihou circuit. However, its positive overall ENEMB relative to the counterfactual is principally driven by lower expected reliability costs. These reliability benefits arise because the Waikato 110 kV network would not need to be operated at N-security during relevant

¹¹ Net market benefit = total quantified cost of the option – total quantified cost of the counterfactual, expressed so that a positive value represents a benefit.

maintenance outages. Under the Ōtorohanga option, a system split would still be required during these outages, limiting access to the Ōtorohanga interconnecting transformer and leaving some Waikato grid exit points exposed to N-security.

5.3 Sensitivity analysis

Sensitivity analysis was undertaken to test whether the preferred option is robust to changes in key investment test assumptions. The parameters assessed were:

- **Discount rate:** Discount rates of 3% and 7%.
- **Value of Expected Unserved Energy (VoEUE):** Values of \$10,000, \$20,000 and \$50,000 per MWh.
- **Capital cost:** Capital costs 30% higher and 30% lower.
- **Probability of failure:** Failure rates 25% lower and 25% higher.
- **Demand forecast:** The three EDGS scenarios were assessed individually.

The following table presents the ENEMB sensitivity results.

Hamilton East remains the highest ranked investment option across all sensitivities assessed, demonstrating its robustness under the range of assumptions tested. It also has a positive ENEMB relative to the counterfactual under most sensitivities. At a VoEUE of \$10,000/MWh, its ENEMB is negative, while at a 7% discount rate it is approximately neutral. These results indicate that the quantified case for investment is sensitive to assumptions that place a lower value on reliability benefits or greater weight on upfront costs.

Table 11: ENEMB sensitivity assessment (\$m, 2026 present value)

Investment test measure	Option 1: Counterfactual	Option 2: Hamilton East	Option 3: Ōtorohanga
Constraint scenario	0.0	0.3	-22.8
Environmental scenario	0.0	7.6	-16.5
Growth scenario	0.0	2.7	-13.3
Standard assumptions (weighted)	0.0	5.1	-17.1
Lower discount rate – 3%	0.0	12.0	-12.6
Higher discount rate - 7%	0.0	0.0	-19.5
VoEUE – \$10,000/MWh	0.0	-1.6	-19.4
VoEUE – \$20,000/MWh	0.0	1.3	-18.4
VoEUE – \$50,000/MWh	0.0	10.1	-15.5
Capital cost – 30% higher	0.0	3.8	-23.2
Capital cost – 30% lower	0.0	6.5	-11.0
Failure rate – 25% higher	0.0	7.6	-16.3
Failure rate – 25% lower	0.0	2.7	-17.9

5.4 Unquantified benefits

5.4.1 Resilience

Based on a high-level qualitative assessment, the Hamilton East option may provide greater resilience benefits than the Ōtorohanga option. Flood risk is a key resilience consideration for both proposed sites; however, available information indicates that this risk may be lower at Hamilton East. The Ōtorohanga site is located in an area susceptible to 1-in-100-year flood events, and has experienced historical flooding associated with the Mangaorongo Stream and Waipā River. In contrast, Hamilton East appears to have a lower exposure to flooding under equivalent conditions.

Preliminary assessment of other resilience threats did not identify any material risks that would significantly differentiate the options.

5.4.2 Generation export

The Cambridge–Karapiro circuit sections can constrain Karapiro generation exports during low-demand, high-generation conditions. The Karapiro Circuit Overload Protection Scheme (COPS) manages this constraint by automatically reducing Karapiro generation following a relevant circuit overload, thereby reducing the need to constrain generation pre-contingency.

The Ōtorohanga option would increase power flows through this part of the network and could therefore increase the frequency or magnitude of generation reductions initiated by the Karapiro COPS during low-demand, high-generation periods. This effect may be greater in the Growth scenario because of additional generation connected at Hinuera and potential future generation at Arapuni South. By comparison, the Hamilton East option is not expected to materially affect operation of the Karapiro COPS.

Any additional generation reductions under the Ōtorohanga option could restrict renewable generation exports and may increase system operating costs. These effects have not been quantified in the investment test but represent a potential unquantified advantage of the Hamilton East option.

5.4.3 Land

Land ownership and security of use are expected to differ between the two options. Transpower acquired land parcels at the Hamilton East site in 2008 which span the area where the 220 kV lines cross-over the 110 kV line. Transpower's ownership of the Hamilton East site does not predetermine the investment test result or the outcome of consultation, but it does provide a clearer and more secure land pathway than the Ōtorohanga option. This reduces delivery risk and provides greater confidence that the preferred option can be implemented in time to meet the forecast need.

By contrast, the Ōtorohanga option may require more complex land access, ownership, or easement arrangements, which could increase programme risk, consenting complexity and stakeholder engagement requirements. These land-related risks have not been quantified in the investment test, but they provide an unquantified advantage for the Hamilton East option because security of the necessary land for construction is important for delivering the project ahead of the forecast need date.

5.4.4 Location

Hamilton East has an unquantified location advantage because it is closer to the main load growth areas around Hamilton, including Ruakura transport hub and industrial developments. This makes it better aligned with potential future demand growth and provides a stronger platform for developing the Waikato 110 kV network over time. By comparison, Ōtorohanga is further from these emerging demand centres and is less directly aligned with growth on the eastern side of Hamilton. This locational benefit has not been quantified in the investment test but supports Hamilton East as the more robust long-term option.

Q8. Do you consider our proposed weighting of the market development scenarios to be appropriate?

- Q9. Do you consider our use of a calculation period of 2030–2049 and a standard discount rate of 5% to be appropriate?
- Q10. Do you have feedback on the preliminary investment test results?
- Q11. Are there any costs, benefits, modelled projects, or sensitivities that should be reviewed or given greater weight?
- Q12. Do you agree with Transpower’s current view that Hamilton East is the preferred option?
- Q13. Do you agree that our preferred option remains robust under sensitivity analysis?
- Q14. Are you aware of any other information that could materially affect the option ranking?

